# 5

# Nonpilot distance protection of transmission lines

## 5.1 Introduction

Distance relays are normally used to protect transmission lines.[1] They respond to the impedance between the relay location and the fault location. As the impedance per mile of a transmission line is fairly constant, these relays respond to the distance to a fault on the transmission line – and hence their name. As will be seen shortly, under certain conditions it may be desirable to make distance relays respond to some parameter other than the impedance, such as the admittance or the reactance, up to the fault location. Any of the relay types described in Chapter 2 can be made to function as a distance relay by making appropriate choices of their design parameters. The $R$–$X$ diagram is an indispensable tool for describing and analyzing a distance relay characteristic, and we will examine it initially with reference to a single-phase transmission line. Similar principles are applicable in case of a three-phase transmission line, provided that appropriate voltages and currents are chosen to energize the distance relay. This matter of energizing voltages and currents in three-phase systems will be considered in detail later.

## 5.2 Stepped distance protection

Before describing the specific application of stepped distance protection, the definitions of underreach and overreach must be addressed. 'Underreaching' protection is a form of protection in which the relays at a given terminal do not operate for faults at remote locations on the protected equipment.[2] This definition states that the relay is set so that it will not see a fault beyond a given distance (e.g. an instantaneous relay should not see the remote bus, as discussed in section 4.4). The distance relay is set to underreach the remote terminal. The corollary to this definition, of course, is that the relay will see faults less than the setting. 'Overreaching' protection is a form of protection in which the relays at one terminal operate for faults beyond the next terminal. They may be constrained from tripping until an incoming signal from a remote terminal has indicated whether the fault is beyond the protected line section.[2] Note the added restriction placed on overreaching protection to avoid loss of coordination.

The zone of distance relays is open at the far end. In other words, the remote point of reach of a distance relay cannot be precisely determined, and some uncertainty about its exact reach must be accepted. This uncertainty of reach is typically about 5 % of the setting. Referring to Figure 5.1(a), the desired zone of protection is shown with a dotted line. The ideal situation would

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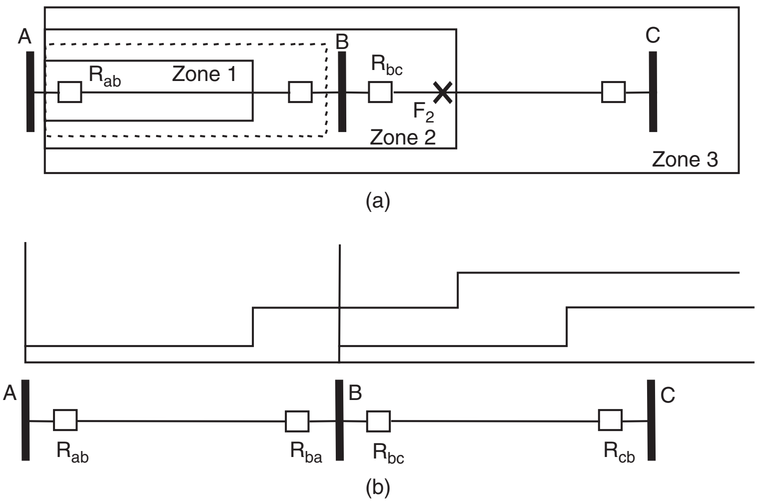


**Figure 5.1** Three-zone step distance relaying to protect 100 % of a line, and back up the neighboring line

be to have all faults within the dotted area trip instantaneously. Owing to the uncertainty at the far end, however, to be sure that we do not overreach the end of the line section, we must accept an underreaching zone (zone 1). It is customary to set zone 1 between 85 and 90 % of the line length and to be operated instantaneously. It should be clear that zone 1 alone does not protect the entire transmission line: the area between the end of zone 1 and bus B is not protected. Consequently, the distance relay is equipped with another zone, which deliberately overreaches beyond the remote terminal of the transmission line.

This is known as zone 2 of the distance relay, and it must be slowed down so that, for faults in the next line section ($F_2$ in Figure 5.1(a)), zone 1 of the next line is allowed to operate before zone 2 of the distance relay at A. This **coordination delay** for zone 2 is usually of the order of 0.3 s, for the reasons explained in Chapter 4.

The reach of the second zone is generally set at 120–150 % of the line length AB. It must be borne in mind that zone 2 of relay $R_{ab}$ must not reach beyond zone 1 of relay $R_{bc}$, otherwise some faults may exist simultaneously in the second zones of $R_{ab}$ and $R_{bc}$, and may lead to unnecessary tripping of both lines. This concept, of coordination by distance as well as by time, leads to a nesting of the zones of protection, and is illustrated in Figure 5.1(b).

It should be noted that the second zone of a distance relay also backs up the distance relay of the neighboring line. However, this is true for only part of the neighboring line, depending upon how far the second zone reaches. In order to provide a backup function for the entire line, it is customary to provide yet another zone of protection for the relay at A. This is known as the third zone of protection, and usually extends to 120–180 % of the next line section. The third zone must coordinate in time and distance with the second zone of the neighboring circuit, and usually the operating time of the third zone is of the order of 1 s. The three zones of protection of the two line sections AB and BC are shown in Figure 5.1(b).

It should also be mentioned that it is not always possible to have acceptable settings for the two overreaching zones of distance relays. Many of these issues will be discussed in greater detail in later sections. However, it is worth noting some of the limiting causes at this time. First, a complication is caused by dissimilar lengths of adjacent lines. If the length of a downstream line is less than 20 % of the line being protected, its zone 2 will certainly overreach the first zone of the

shorter line. Similarly, the zone 3 of the first line may overreach the zone 2 of the next line. The guidelines for setting the reach of zones mentioned above must be considered to be approximate, and must be adjusted to meet a specific situation at hand. Zone 3 was originally applied as a remote backup to zones 1 and 2 of an adjacent line in the event that a relay or breaker failure prevented clearing the fault locally.[3] The reach setting, however, is a complex problem and is the subject of many ongoing studies and suggestions which will be discussed in detail in Chapters 5, 10 and 11. Briefly, however, the zone 3 characteristic must provide protection against faults but should not operate for normal, albeit unusual, system conditions such as heavy loads or stability swings. Computer relaying makes provision for identifying heavy loads or stability swings through its load encroachment feature which is discussed further in Chapter 11. Another consideration is the effect of the fault current contributions from lines at the intermediate buses. This is the problem of infeed, and will be discussed in greater detail later.

**Example 5.1**

Consider the transmission system shown in Figure 5.2. The relay $R_{ab}$ is to be set to protect the line AB, and back up the two lines BC and BD. The impedances of the three lines are as shown in Figure 5.2. (Note that these impedances are in primary ohms – i.e. actual ohms of the transmission lines. Normally, the settings are expressed in secondary ohms, as will be explained in section 5.3.) Zone 1 setting for $R_{ab}$ is $0.85 \times (4 + j30)$, or $(3.4 + j25.5)\ \Omega$. Zone 2 is set at $1.2 \times (4 + j30)$, or $(4.8 + j36)\ \Omega$. Since the relay $R_{ab}$ must back up relays $R_b$ and $R_{bd}$, it must reach beyond the longer of the two lines. Thus, zone 3 is set at $[(4 + j30) + 1.5 \times (7 + j60)]$, or at $(14.5 + j120)\ \Omega$. The time delays associated with the second and third zones should be set at about 0.3 and 1.0 s, respectively.

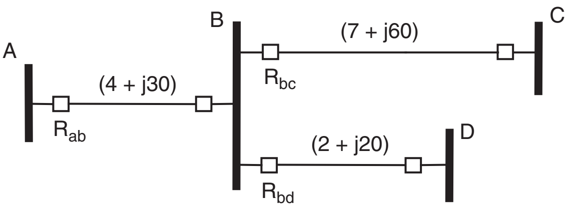


**Figure 5.2** System for Example 5.1

It should be noted that if one of the neighboring lines, such as line BD, is too short, then the zone 2 setting of the relay $R_{ab}$ may reach beyond its far end. For the present case, this would happen if the impedance of line BD is smaller than $[(4.8 + j36) - (4.0 + j30)] = (0.8 + j6)\ \Omega$. In such a case, one must set zone 2 to be a bit shorter, to make sure that it does not overreach zone 1 of $R_{bd}$, or, if this is not possible, zone 2 of the relay $R_{ab}$ may be set longer than zone 2 of relay $R_{bd}$ or it may be dispensed with entirely and only zone 3 may be employed as a backup function for the two neighboring lines.

The control circuit connections to implement the three-zone distance relaying scheme are shown in Figure 5.3. The seal-in unit contact shown is typical for all three phases, and the seal-in coil may

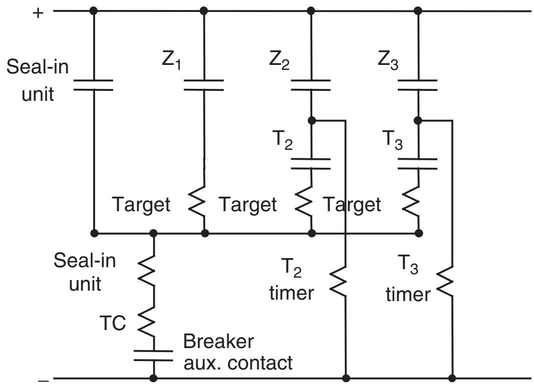


**Figure 5.3** Control circuit for a three-zone step distance relay

be combined with the target coils in some designs. The three distance measuring elements $Z_1$, $Z_2$ and $Z_3$ close their contacts if the impedance seen by the relay is inside their respective zones. The zone 1 contact activates the breaker trip coil(s) immediately (i.e. with no intentional time delay), whereas the zones 2 and 3 contacts energize the two timing devices $T_2$ and $T_3$, respectively. Once energized, these timing devices close their contacts after their timer settings have elapsed. These timer contacts also energize the breaker trip coil(s). Should the fault be cleared before the timers run out, $Z_2$, $Z_3$, $T_2$ and $T_3$ will reset as appropriate in a relatively short time (about 1–4 ms).

We should remember that the zone settings for zones 2 and 3 are affected by the contributions to the fault current made by any lines connected to the intervening buses, i.e. buses B and C in Figure 5.1. This matter has been dealt with in the discussion of infeed and outfeed in section 4.3, and similar considerations apply here as well. The problem is caused by the different currents seen by the relays as a result of the system configuration. As shown in Example 4.6, the operating currents in the upstream relays change significantly if parallel lines are in or out of service.

## 5.3 $R$–$X$ diagram

In general, all electromechanical relays respond to one or more of the conventional torque-producing input quantities: (a) voltage, (b) current, (c) product of voltage, current and the angle $\theta$ between them and (d) a physical or design force such as a control spring.[4] Similar considerations hold for solid-state relays as well. For the product-type relay, such as the distance relay, analyzing the response of the relay for all conditions is difficult because the voltage varies for each fault, or varies for the same fault but with different system conditions.

To resolve this difficulty, it is common to use an $R$–$X$ diagram to both analyze and visualize the relay response. By utilizing only two quantities, $R$ and $X$ (or $Z$ and $\theta$), we avoid the confusion introduced by using the three quantities $E$, $I$ and $\theta$. There is an additional significant advantage in that the $R$–$X$ diagram allows us to represent both the relay and the system on the same diagram.

Consider an ideal (zero resistance) short circuit at location F in the single-phase system shown in Figure 5.4. The distance relay under consideration is located at line terminal A. The primary voltage and current at the relay location are related by

$$Z_{\mathrm{f,p}} = \frac{E_{\mathrm{p}}}{I_{\mathrm{p}}} \tag{5.1}$$

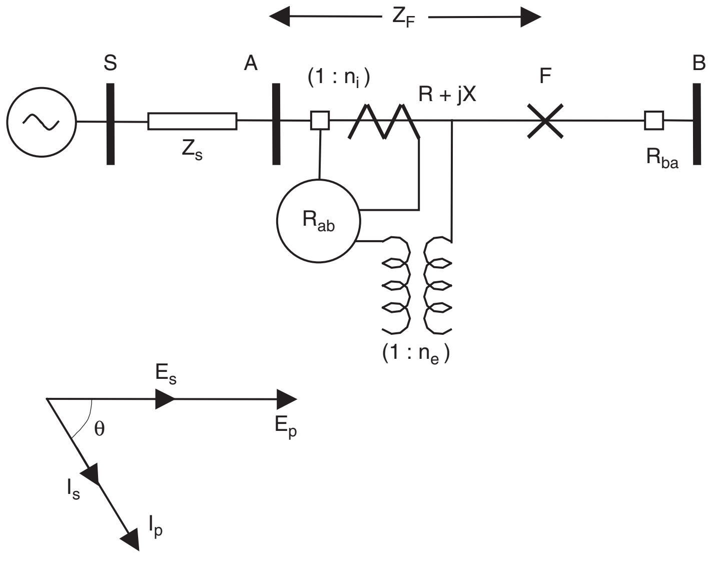


**Figure 5.4** Voltage, current and impedance as seen by the relay

where the subscript 'p' represents primary quantities. In terms of the secondary quantities of voltage and current transformers, the relay sees the primary impedance $Z_{f,p}$ as $Z_{f,s}$, where

$$Z_{f,s} = \frac{E_s}{I_s} = Z_{f,p}\frac{n_i}{n_e} \tag{5.2}$$

where $n_i$ and $n_e$ are the current transformer (CT) and voltage transformer (VT) turns ratios. It is customary to suppress the subscript 's', with the understanding that the secondary quantities are always implied. Thus, we will mean $Z_{f,s}$ when we use $Z_f$.

### Example 5.2

Consider a distance relaying system utilizing a CT with a turns ratio of 500 : 5 and a VT with a turns ratio of 20 000 : 69.3. Thus, the CT ratio $n_i$ is 100, while the VT ratio $n_e$ is 288.6. The impedance conversion factor $n_i/n_e$ for this case is (100/288.6), or 0.3465. All primary impedances must be multiplied by this factor to obtain their secondary values. Thus, the line in Example 5.1 with an impedance of $(4 + j30)\ \Omega$ primary would appear to be $(1.386 + j10.395)\ \Omega$ secondary.

The zone 1 setting for this line would be 85 % of this impedance, or $(1.17 + j8.84)\ \Omega$ secondary. Of course, the actual setting used would depend upon the nearest value which is available on a given relay.

Although we have defined $Z_f$ under fault conditions, it must be borne in mind that the ratio of $E$ and $I$ at the relay location is an impedance under all circumstances, and when a fault occurs, this impedance assumes the value $Z_f$. In general, the ratio $E/I$ is known as the apparent impedance

'seen' by the relay. This impedance may be plotted as a point on the complex $R-X$ plane. This is the plane of (apparent) secondary ohms. **One could view the impedance as the voltage phasor, provided that the current is assumed to be the reference phasor, and of unit magnitude.** This way of looking at the apparent impedance seen by a relay as the voltage phasor at the relay location is often very useful when relay responses to changing system conditions are to be determined. For example, consider the apparent impedance seen by the relay when there is normal power flow in the transmission line. If the load current is of constant magnitude, and the sending end voltage at the relay location is constant, the corresponding voltage phasor, and hence the impedance, will describe a circle in the $R-X$ plane. Lighter loads – meaning a smaller magnitude of the current – produce circles of larger diameters. Similarly, when the load power factor is constant, the corresponding locus of the impedance is a straight line through the origin. Figure 5.5 shows these contours for varying load current magnitudes and power factors. Note that when the real power flows into the line, the corresponding apparent impedances lie in the right half of the plane, while a reversed power flow maps into the left half-plane. Similarly lagging power factor load plots in the upper half-plane, while a leading power factor load plots in the lower half-plane. Zero power transfer corresponds to points at infinity. A line open at the remote end will have leading reactive current, and hence the apparent impedance will map at a large distance along the negative $X$ axis.

Now consider the fault at location F as shown in Figure 5.4. The corresponding apparent impedance is shown at F in Figure 5.5. As the location of the fault is moved along the transmission line, the point F moves along the straight line AB in Figure 5.5. Thus, the transmission line as seen by the relay maps into the line AB in the $R-X$ plane. The line AB makes an angle $\theta$ with the $R$ axis, where $\theta$ is the impedance angle of the transmission line. (For an overhead transmission line, $\theta$ lies between 70° and 88°, depending upon the system voltage, the larger angles being associated with higher transmission voltages.) When the fault is on the transmission line, the apparent impedance plots on the line AB; for all other faults or loading conditions, the impedance plots away from the line AB. Often it is convenient to plot the source impedance $Z_s$ also on the $R-X$ diagram, as shown in Figure 5.5.

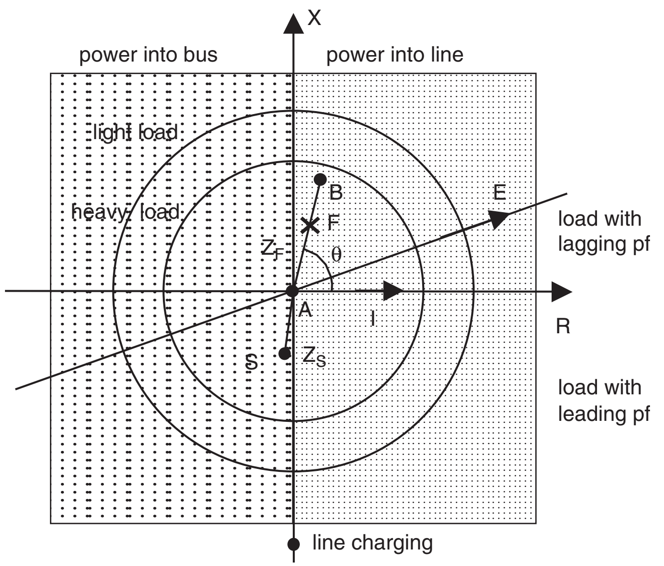


**Figure 5.5** $R-X$ diagram as a special case of the phasor diagram (pf, power factor)

**Example 5.3**

Let the rated load for the transmission line shown in Figure 5.4 be 8 MVA. This corresponds to 400 A at the rated voltage of 20 000 V. The apparent impedance corresponding to this load is (20 000/400) = 50 Ω primary. In terms of secondary ohms, this impedance becomes 50 × 0.3465 = 17.32 Ω. Thus, a load of 8 MVA at 0.8 pf lagging is 17.32 × (0.8 + j0.6) = (13.86 + j10.4) Ω secondary. This is shown as $L_1$ in Figure 5.6. A load of 8 MVA with a leading power factor of 0.8 is (13.86 − j10.4) Ω secondary, which maps as point $L_2$. Similarly, 8 MVA flowing from B to A maps into $L_3$ and $L_4$ for leading and lagging power factors, respectively.

The line impedance of (1.39 + j10.4) Ω secondary maps into point B while the zone 1 setting of (1.17 + j8.84) Ω maps into the point $Z_{1a}$. A similar relay located at B would have its zone 1 map at $Z_{1b}$. If we assume the equivalent source impedances as seen at buses A and B to be j10 and j8 Ω primary respectively, they will be j3.46 and j2.77 Ω secondary respectively, as shown by points $S_1$ and $S_2$ in Figure 5.6. If the line-charging current is 15 A, the apparent impedance seen by the relay at A when the breaker at terminal B is open is −j(20 000/15) = −j1333 Ω primary, or −j461.9 Ω secondary. This is shown as the point C, on a telescoped $y$ axis in Figure 5.6. The zones of protection of a relay are defined in terms of its impedance, and hence it is necessary that they cover areas in the immediate neighborhood of the line AB. As the load on the system increases, the possibility of it encroaching upon the protection zones becomes greater. Ultimately, at some values of the load, the relay is in danger of tripping. The $R-X$ diagram offers a convenient method of analyzing whether this is the case. A fuller account of the loadability of a distance relay is considered in section 5.11.

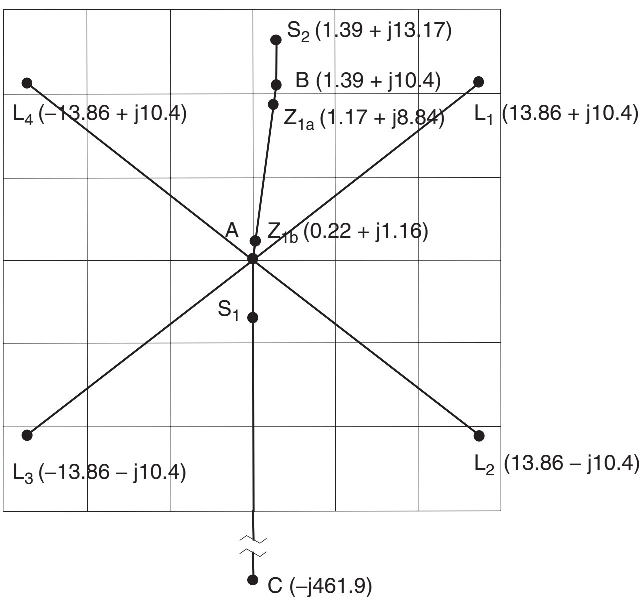


**Figure 5.6** $R-X$ diagram for Example 5.3

## 5.4 Three-phase distance relays

On a three-phase power system, there are ten distinct types of possible faults: a three-phase fault, three phase-to-phase faults, three phase-to-ground faults and three double-phase-to-ground faults. The equations that govern the relationship between voltages and currents at the relay location are different for each of these faults. We should therefore expect that it will take several distance relays, each of them energized by a different pair of voltage and current inputs, to measure the distance to the fault correctly. It is a fundamental principle of distance relaying that, regardless of the type of fault involved, the voltage and current used to energize the appropriate relay are such that the relay will measure the positive sequence impedance to the fault.[5] Once this is achieved, the zone settings of all relays can be based upon the total positive sequence impedance of the line, regardless of the type of the fault. We will now consider various types of fault, and determine the appropriate voltage and current inputs to be used for the distance relays responsible for each of these fault types.

### *5.4.1 Phase-to-phase faults*

Consider a fault between phases b and c of a three-phase transmission line. We may consider this to be the fault at location F in Figure 5.4, provided we view that figure as a one-line diagram of the three-phase system. The symmetrical component representation for this fault is shown in Figure 5.7. The positive and negative sequence voltages at the fault bus are equal, and are given by

$$E_{1f} = E_{2f} = E_1 - Z_{1f}I_1 = E_2 - Z_{1f}I_2 \tag{5.3}$$

where $E_1$, $E_2$, $I_1$ and $I_2$ are the symmetrical components of voltages and currents at the relay location, and the positive and negative sequence impedances of the transmission line are equal. It follows from equations (5.3) that

$$\frac{E_1 - E_2}{I_1 - I_2} = Z_{1f} \tag{5.4}$$

Also, since the phase quantities at the relay location are given by

$$E_b = E_0 + \alpha^2 E_1 + \alpha E_2 \text{ and } E_c = E_0 + \alpha E_1 + \alpha^2 E_2 \tag{5.5}$$

then

$$(E_b - E_c) = (\alpha^2 - \alpha)(E_1 - E_2) \text{ and } (I_b - I_c) = (\alpha^2 - \alpha)(I_1 - I_2) \tag{5.6}$$

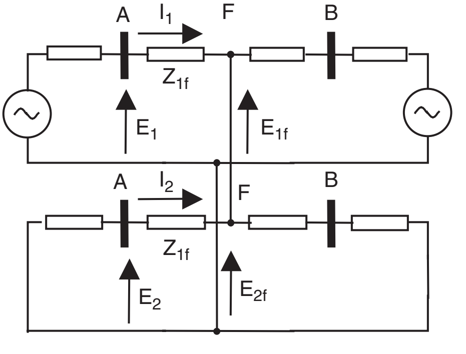


**Figure 5.7** Symmetrical component circuit for b–c fault

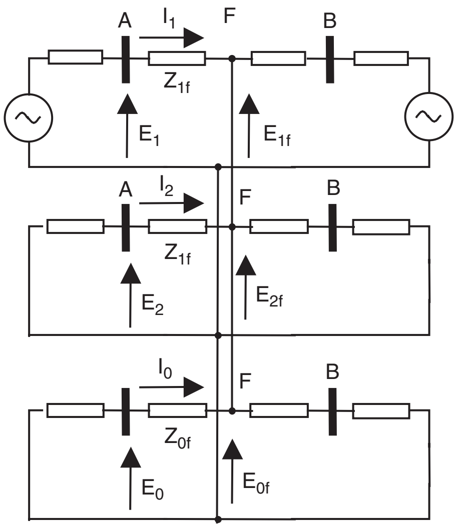


**Figure 5.8** Symmetrical component circuit for b–c–g fault

Substituting from equations (5.6) in equation (5.4) gives

$$\frac{E_b - E_c}{I_b - I_c} = \frac{E_1 - E_2}{I_1 - I_2} = Z_{1f}A \tag{5.7}$$

Thus, a distance relay, to which the line-to-line voltage between phases b and c is connected, and which is supplied by the difference between the currents in the two phases, will measure the positive sequence impedance to the fault, when a fault between phases b and c occurs. Similar analysis will show that, for the other two types of phase-to-phase fault, when the corresponding voltage and current differences are used to energize the relays, the positive sequence impedance to the fault will be measured.

The symmetrical component diagram for a phase-b-to-c-to-ground fault is shown in Figure 5.8. It should be clear from this figure that for this fault also, the performance equations for the positive and negative sequence parts of the equivalent circuit are exactly the same as those for the b-to-c fault. Finally, for a three-phase fault at F, the symmetrical component diagram is as shown in Figure 5.9. For this case

$$\begin{aligned} E_1 &= E_a = Z_{1f}I_1 = Z_{1f}I_a \\ E_2 &= E_0 = 0 \\ I_2 &= I_0 = 0 \end{aligned} \tag{5.8}$$

Also, for this case, $E_a = E_1$, $E_b = \alpha^2 E_1$ and $E_c = \alpha E_1$, and similar relations hold for the phase currents. Consequently, for a three-phase fault

$$\frac{E_a - E_b}{I_a - I_b} = \frac{E_b - E_c}{I_b - I_c} = \frac{E_c - E_a}{I_c - I_a} = Z_{1f} \tag{5.9}$$

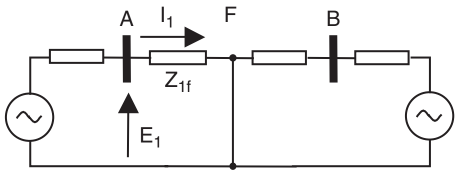


**Figure 5.9** Symmetrical component circuit for a three-phase fault

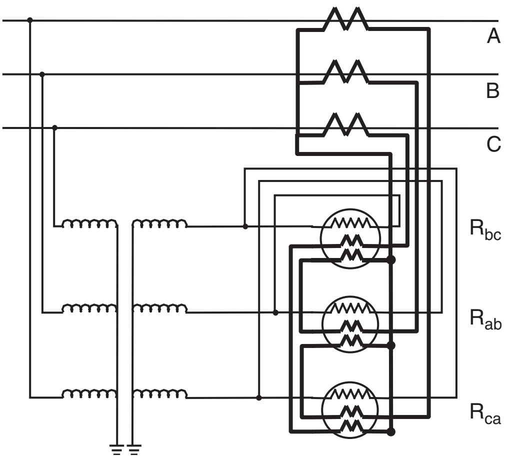


**Figure 5.10** Current transformer and voltage transformer connections for distance relays for phase faults

The differences of phase voltages and currents used in equation (5.9) are known as 'delta' voltages and currents, and we see that relays energized by the delta voltages and currents respond to the positive sequence impedance to a multiphase fault. A complement of three phase distance relays covers the seven multiphase faults between them. For double-phase or double-phase-to-ground faults, one of the three relays measures the positive sequence impedance to the fault, while, for a three-phase fault, all three relays measure the correct impedance. The connections for the phase relays are shown schematically in Figure 5.10.

### *5.4.2 Ground faults*

For a fault between phase a and ground, the symmetrical component connection diagram is as shown in Figure 5.11. The voltages and currents at the relay location for this case are given by

$$\begin{aligned} E_{1f} &= E_1 - Z_{1f}I_1 \\ E_{2f} &= E_2 - Z_{1f}I_2 \\ E_{0f} &= E_0 - Z_{0f}I_0 \end{aligned} \tag{5.10}$$

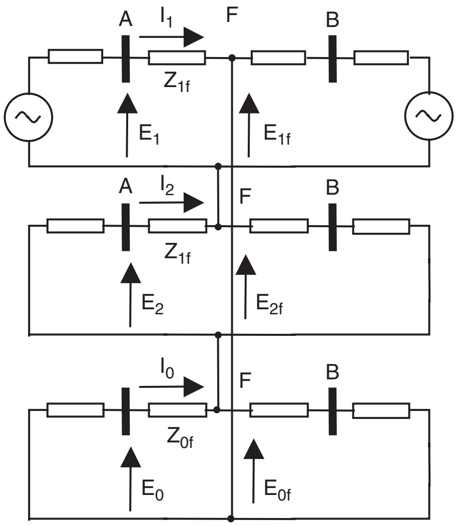


**Figure 5.11** Symmetrical component circuit for an a–g fault

The phase a voltage and current can be expressed in terms of the symmetrical components and the voltage of phase a at the fault point can be set equal to zero:

$$\begin{aligned} E_{\mathrm{af}} &= E_{0\mathrm{f}} + E_{1\mathrm{f}} + E_{2\mathrm{f}} \\ &= (E_0 + E_1 + E_2) - Z_{1\mathrm{f}}(I_1 + I_2) - Z_{0\mathrm{f}}I_0 = 0 \qquad (5.11) \\ &= E_{\mathrm{a}} - Z_{1\mathrm{f}}I_{\mathrm{a}} - (Z_{0\mathrm{f}} - Z_{1\mathrm{f}})I_0 = 0 \qquad (5.12) \end{aligned}$$

where $I_{\mathrm{a}}$ has been substituted for the sum $(I_0 + I_1 + I_2)$ in equation (5.12). Finally, a new current $I'_{\mathrm{a}}$ is defined as follows:

$$I'_{\mathrm{a}} = I_{\mathrm{a}} + \frac{Z_{0\mathrm{f}} - Z_{1\mathrm{f}}}{Z_{1\mathrm{f}}} I_0 = I_{\mathrm{a}} + \frac{Z_0 - Z_1}{Z_1} I_0 = I_{\mathrm{a}} + mI_0 \qquad (5.13)$$

where, in equation (5.13), $Z_0$ and $Z_1$ are the zero and positive sequence impedances of the entire line. The factor $m$ is known as a compensation factor, which compensates the phase current for the mutual coupling between the faulted phase and the other two unfaulted phases. It follows from equation (5.12) that for a phase-a-to-ground fault

$$\frac{E_{\mathrm{a}}}{I'_{\mathrm{a}}} = Z_{1\mathrm{f}} \qquad (5.14)$$

Thus, if the distance relay is energized with the phase a voltage, and the compensated phase a current, it also measures the positive sequence impedance to the fault. The factor $m$ for most overhead transmission lines is a real number, and varies between 1.5 and 2.5. A good average

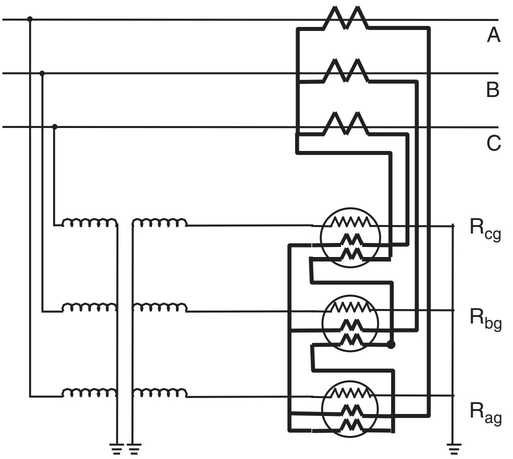


**Figure 5.12** Current transformer and voltage transformer connections for distance relays for ground faults

value for $m$ is 2.0, which corresponds to $Z_0$ of a transmission line being equal to $3Z_1$. As in the case of phase relays, it takes three ground distance relays to cover the three single-phase-to-ground faults. It should be noted that for a three-phase fault, the compensated phase current becomes $I_a$, since there is no zero sequence current for this fault. For this case, equation (5.14) is identical to equation (5.18), and hence the three ground distance relays also measure the correct distance to the fault in the case of a three-phase fault. A schematic connection diagram for the three ground distance relays is shown in Figure 5.12. A full complement of phase and ground distance relays will require six distance measuring elements connected as shown in Figures 5.10 and 5.12.

### Example 5.4

Consider the simple system represented by the one-line diagram in Figure 5.13. The system nominal voltage is 13.8 kV, and the positive and zero sequence impedances of the two elements are as shown in the figure. The zero sequence impedances are given in parentheses. We will verify the distance calculation equations (5.9) and (5.14) for three-phase, phase-to-phase and phase-to-ground faults.

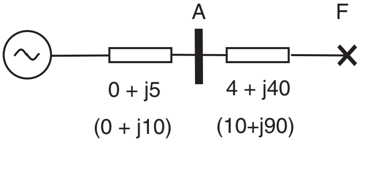


**Figure 5.13** System for fault impedance calculation

### Three-phase fault

For this case, only the positive sequence current exists, and is also the phase a current. It is given by

$$I_a = I_1 = \frac{7967.4}{4 + j45} = 176.36\angle 84.92^\circ$$

$7967.4 = (13\,800/\sqrt{3})$ is the phase-to-neutral voltage. The phase a voltage at the relay location is given by

$$E_a = E_1 = 7967.4 - j5 \times 176.36\angle 84.92^\circ = 7089.49\angle -0.63^\circ$$

Thus, the fault impedance seen by the relay in this case is

$$Z_f = \frac{E_a - E_b}{I_a - I_b} = \frac{E_a}{I_a} = \frac{7089.49\angle -0.63^\circ}{176.36\angle -84.92^\circ} = 4 + j40\ \Omega$$

**Phase-to-phase fault**

For a b–c fault

$$I_1 = -I_2 = \frac{7967.4}{2 \times (4 + j45)} = 88.18\angle 84.92^\circ$$

Also, $I_b = -I_c = I_1(\alpha_2 - \alpha) = -j\sqrt{(3)}I_1 = 152.73\angle -174.92^\circ$. And, $(I_b - I_c) = 305.46\angle -174.92^\circ$. The positive and negative sequence voltages at the relay location are given by

$$E_1 = 7967.4 - j5 \times 88.18\angle -84.92^\circ = 7528.33\angle -0.3^\circ$$
$$E_2 = j5 \times 88.18\angle -84.92^\circ = 440.90\angle 5.08^\circ$$

and the phase b and c voltages at the relay location are

$$E_b = \alpha^2 E_1 + \alpha E_2 = 7528.33\angle -120.3^\circ + 440.90\angle 125.08^\circ$$
$$= -4051.3 - j6139.3$$
$$E_c = \alpha E_1 + \alpha^2 E_2 = 7528.33\angle 119.7^\circ + 440.90\angle -114.9^\circ$$
$$= -3916.09 + j6139.3$$

Thus, $E_b - E_c = 12279.37\angle -90.63^\circ$, and

$$\frac{E_b - E_c}{I_b - I_c} = \frac{12\,279.37\angle -90.63^\circ}{305.46\angle -174.92^\circ} = 4 + j40\ \Omega$$

**Phase-a-to-ground fault**

For this fault, the three symmetrical components of the current are equal:

$$I_1 = I_2 = I_0 = \frac{7967.4}{(0 + j10) + 2 \times (0 + j5) + (10 + j90) + 2 \times (4 + j40)}$$
$$= 41.75\angle -84.59^\circ$$

The symmetric components of the voltages at the relay location are

$$E_1 = 7967.4 - j5 \times 41.75\angle -84.59^\circ = 7759.58 - j19.68$$
$$E_2 = -j5 \times 41.75\angle -84.59^\circ = -207.82 - j19.68$$
$$E_0 = -(0 + j10) \times 41.75\angle -84.59^\circ = -415.64 - j39.36$$

And the phase a voltage and current at the relay location are

$$E_\mathrm{a} = E_1 + E_2 + E_0 = 7136.55\angle -0.63^\circ$$
$$I_\mathrm{a} = I_1 + I_2 + I_0 = 125.25\angle -84.59^\circ$$

The zero sequence current compensation factor $m$ is given by

$$m = \frac{Z_0 - Z_1}{Z_1} = \frac{1 - \mathrm{j}90 - 4 - \mathrm{j}40}{4 + \mathrm{j}40} = 1.253\angle -1.13^\circ$$

and the compensated phase a current is $I'_\mathrm{a} = I_\mathrm{a} + mI_0 = 177.54\angle -84.92^\circ$; and, finally

$$\frac{E_\mathrm{a}}{I'_\mathrm{a}} = \frac{7136.55\angle -0.63^\circ}{177.54\angle -84.92^\circ} = 4 + \mathrm{j}40\ \Omega$$

### *5.4.3 Relays in unfaulted phases*

Although there are three phase-distance and three ground-distance relays in use for protection against all ten types of fault on a three-phase system, only one of these relays measures the correct distance to the fault for a specific fault type, and it is interesting to see what the remaining relays measure. In general, they measure impedances that are greater than the impedance to the fault. However, under certain conditions – such as for close-in faults – the distance measured by the other relays may be such that an erroneous operation of some of the other relays may result. Of course, if the protection system is designed to trip all three phases for every fault, the fact that one or more relays may operate for one fault is of no practical significance, although erroneous targets produced by some of the relays may lead to unnecessary confusion in postmortem analysis of the fault, and is to be avoided if at all possible. Only when single-phase tripping for phase-to-ground fault is to be used does it become a matter of concern if a phase distance relay responds (erroneously) to a ground fault, and causes a three-phase trip. We will therefore consider the operation of the phase distance relays for a fault on phase a. Similar analysis can be carried out for all the distance relays in the unfaulted phases for each of the fault types.[6]

Consider the phasor diagram for a phase-a-to-ground fault on a radial system as shown in Figure 5.14. The prefault voltages and currents are represented by the unprimed quantities, while the faulted quantities are shown with primes. This being an unloaded radial system, no prefault current exists. The phase a voltage at the relay location drops to a small value during the fault, while the current in phase a lags the phase a voltage by the impedance angle of the combination $(Z_1 + Z_2 + Z_0)$. The voltages of the unfaulted phases will change in magnitude and angle as shown in the phasor diagram. The compensated phase current as defined by equation (5.13) for this case (since $I_\mathrm{a} = 3I_0$) is given by $I'_\mathrm{a} = (1 + m/3)I_\mathrm{a}$. The phase distance relays use delta currents, and since $I_\mathrm{b} = I_\mathrm{c} = 0$, the three delta currents for this fault are $(I_\mathrm{a} - I_\mathrm{b}) = I_\mathrm{a}$, $(I_\mathrm{c} - I_\mathrm{a}) = -I_\mathrm{a}$ and $(I_\mathrm{b} - I_\mathrm{c}) = 0$. These delta currents and voltages are also shown in Figure 5.14.

Remember that the impedance seen by any relay is equal to its voltage when the corresponding current is taken as a reference phasor of unit magnitude. Since the delta current for the b–c relay is zero for this fault, it sees an infinite impedance, and will not mis-operate. As the delta currents for the a–b and c–a relays are $I_\mathrm{a}$ and $-I_\mathrm{a}$, respectively, we can visualize their response to this fault by redrawing the delta voltages $E_\mathrm{ab}$ and $E_\mathrm{ca}$ with $I_\mathrm{a}$ and $-I_\mathrm{a}$ as the reference unit phasors, and adjust (increase) the magnitude of the two voltage phasors by the factor $(1 + m/3)$, in relation to the

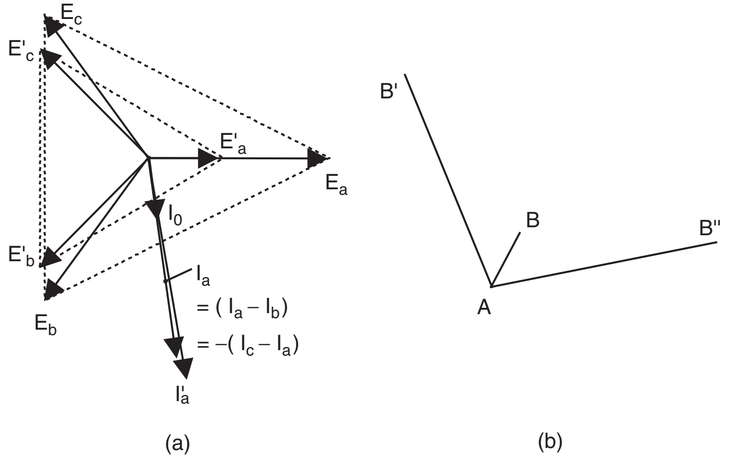


**Figure 5.14** Phasor diagram for phase-a-to-ground fault: (a) voltages and currents; (b) apparent impedances

phase a voltage. This last adjustment is necessary because the phase a voltage is seen as the fault impedance with $I'_a = (1 + m/3)I_a$ as the unit of measurement, whereas $E_{ab}$ and $E_{ca}$ are the fault impedances seen by those two relays with $\pm I_a[= \pm I'_a/(1 + m/3)]$ as the units of measurement. Thus, the impedances seen by the a–g, a–b and c–a relays for the a–g fault are seen to be AB, AB′ and AB″, respectively, as shown in Figure 5.14. It should be clear that for a ground fault near the relay location, the a–b and c–a relays may mis-operate, if the protection zone covers AB′ and AB″ for small values of AB.

The analysis presented above must be modified to include the effect of prefault load. The load current will change the current phasors, and hence the impedances seen by the relays. Such effects are of less importance in a qualitative discussion, and the reader is referred to the reference cited[6] for a more detailed treatment of the subject.

### *5.4.4 Fault resistance*

In developing distance relay equations, we assumed that the fault under consideration was an ideal (i.e. zero resistance) short circuit. In reality, for multiphase faults the fault arc will be between two high-voltage conductors, whereas for ground faults the fault path may consist of an electrical arc between the high-voltage conductor and a grounded object – such as the shield wire, or the tower itself.

In either case, the fault path will have a resistance in it, which may consist of an arc resistance or an arc resistance in series with the tower footing resistance in the case of a ground fault. The tower footing resistance is practically constant during the fault (and ranges between 5 and 50 Ω), whereas the arc resistance changes in time as the fault current continues to flow. During the early period of the arc, say in the first few milliseconds, the arc resistance is negligible, and as the arc channel gets elongated in time, the arc resistance increases. For relaying considerations, it is generally assumed that the arc resistance is a constant, given by an empirical formula[7,8]

$$R_{arc} = \frac{76V^2}{S_{sc}} \tag{5.15}$$

where $V$ is the system voltage in kV and $S_{sc}$ is the short-circuit kVA at the fault location. For example, the fault arc resistance for a 345 kV transmission line fault at a place with short-circuit

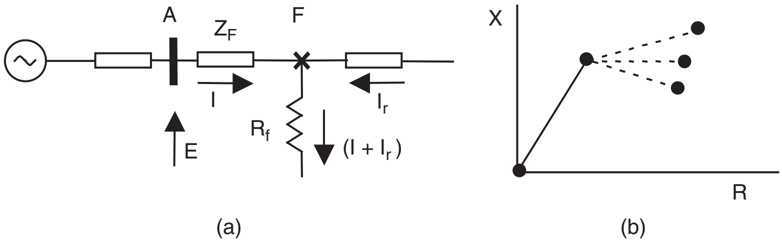


**Figure 5.15** Fault path resistance, and its effect on the $R-X$ diagram

capacity of 1500 MVA is $(76 \times 3452/1500 \times 103) \cong 50\ \Omega$. The fault resistance introduces an error in the fault distance estimate, and hence may create an unreliable operation of a distance relay. Consider the single-phase transmission system shown in Figure 5.15(a), and assume that the fault resistance is equal to $R_f$. If the contribution to the fault from the remote end is $I_r$, the fault current $I_f = I + I_r$, and the voltage at the relay location is given by

$$E = Z_f I + R_f(I + I_r) \tag{5.16}$$

The apparent impedance $Z_a$ seen by the relay is

$$Z_a = E/I = Z_f + R_f\left(\frac{I_r}{I} + 1\right) \tag{5.17}$$

Since $I_r$ may not be in phase with $I$, the fault resistance may contribute an error to the resistance as well as the reactance of the faulted line segment. This is illustrated in the $R-X$ diagram in Figure 5.15(b). In order to accommodate the resistance in the fault path, it is necessary to shape the trip zone of a distance relay in such a manner that the region surrounding the apparent impedance is included inside the zone. It will be seen in section 5.11 that different types of distance relay have differing ability of accommodating the fault resistance. It should be remembered that a larger area for the protection zone in the $R-X$ plane accommodates greater fault path resistance, while it also affects the loadability of the relay.

### Example 5.5

Assume a single-phase circuit as shown in Figure 5.15(a), and let the line impedance to the fault point be $(4 + j40)\ \Omega$, while the fault resistance is $10\ \Omega$. Let the current to the fault in the line in question be $400\angle -85^\circ$ amps, while the current contribution to the fault from the remote end is $600\angle -90^\circ$ amps. Then, the apparent impedance seen by the relay, as given by equation (5.17), is

$$Z_a = (4 + j40) + 10\left(1 + \frac{600\angle -90^\circ}{400\angle -85^\circ}\right) = 28.94 + j38.69\ \Omega$$

If the receiving end current contribution is in phase with the sending end current, the error in $Z_a$ will be in the real part only. That is not the case here, and hence the reactance also is in error.

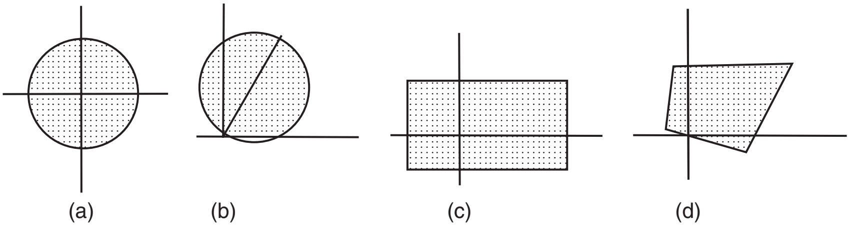


**Figure 5.16** Types of impedance relay characteristics

## 5.5 Distance relay types

Distance relays may be classified according to the shape of their zones of operation. Traditionally, all zone shapes have been circular, because an electromechanical relay, with the torque equation (2.15), produces a circular boundary for the zones of operation. Some of the terminology used in describing the zones (e.g. 'the line of maximum torque') dates back to the electromechanical origins of distance relays. However, far more complex zone shapes can be achieved with modern solid-state and computer relays, although some of the older terminology continues to be used in describing the latter relays.

Four general relay types are recognized according to the shapes of their operating zones: (1) impedance relays, (2) admittance or mho relays, (3) reactance relays and (4) quadrilateral relays. These four relay characteristic shapes are illustrated in Figure 5.16. The impedance relay has a circular shape centered at the origin of the $R-X$ diagram. The admittance (or mho) relay has a circular shape which passes through the origin. The reactance relay has a zone boundary defined by a line parallel to the $R$ axis. The zone extends to infinity in three directions as shown in Figure 5.16(c). The quadrilateral characteristic, as the name implies, is defined by four straight lines. This last characteristic is only available in solid-state or computer relays. More complex shapes can be obtained by using one or more of the above relay types, in a logical combination to provide a composite tripping zone boundary.

## 5.6 Relay operation with zero voltage

It will be recalled that the generalized torque equation for an electromechanical relay, as given by equation (2.15), is adapted to a directional relay or a mho relay by appropriate choices of various constants appearing in that equation. Thus, the balance point equation for a directional relay is equivalent to $[VI\sin(\theta+\varphi)=0]$, whereas for a mho relay the corresponding equation is $[V=IZ_{\mathrm{r}}\sin(\theta+\varphi)]$. At $V=0$, both of these equations lead to uncertainties of operation. The directional relay equation is satisfied by any value of $I$ and $\theta$ for $V=0$, while for the mho relay equation, if $V$ is zero, the angle between $V$ and $IZ_{\mathrm{r}}$ cannot be determined, and the operation of the relay becomes uncertain. The region around the origin in both of these characteristics is poorly defined as to the performance of the relay (see Figure 2.13). Consequently, a zero voltage fault is likely to be misjudged as to its direction by both of these relays.

It is possible to design relays which will overcome the problem of zero-voltage faults. A common technique is to provide a memory-action circuit in the voltage coil, which, due to a subsidence transient, will sustain the prefault voltage in the polarizing circuit for a few cycles after the occurrence of the zero-voltage fault. The phase angle of the voltage impressed by the memory circuit on the voltage coil is very close to that of the voltage before the occurrence of the fault. Since the memory action is provided by a transient that may last only a few cycles, this feature can be used in high-speed relaying functions only.

Memory action requires that the prefault voltage seen by the relay is normal, or close to normal. If there is no prefault voltage in the primary circuit (as would be the case if the transmission line is being energized after having been de-energized for some time, and line-side potential is being used for relaying) no memory action is available. This is a common situation when live tank circuit breakers are being used (section 1.5). It should be remembered that a true zero-voltage fault is somewhat rare, and can only be caused if grounding chains or switches are left connected by maintenance crews on unenergized power apparatus. To provide adequate protection against a zero-voltage fault, an instantaneous overcurrent relay can be used to reach just beyond the relay location. The impedance for a fault just beyond the reach of the instantaneous relay will provide enough of a voltage drop to provide reliable operation of the impedance unit. There is, of course, a setting problem with an instantaneous relay. Since it is nondirectional, there must be inherent discrimination between forward and backward faults.

Since the instantaneous relay is not directional, it may not be possible to set it to discriminate between faults in the protected zone and faults behind the relay. A common solution is to use an instantaneous overcurrent relay that is normally inoperative, but is made operative as soon as the breaker closes. The relay remains in the circuit for 10–15 cycles, allowing the breaker to trip in primary or breaker-failure time, after which the relay is removed from service. It is, of course, assumed that there is little likelihood of a backward fault occurring during the short time that the instantaneous relay is in the circuit.

In the case of computer-based distance relays, it is a simple matter to provide memory action by storing prefault data for as long a duration as one wishes. Thus, it may be possible to provide memory action for reclosing functions as well, when prefault voltage may not exist for several seconds prior to the reclosing action. Of course, one cannot use memory voltage functions over very long periods of time, as the phase angle of the memory voltage may no longer be valid due to small deviations and drifts in the power system frequency.

## 5.7 Polyphase relays

The distance relays discussed so far have all been essentially single-phase devices, i.e. every fault will result in the operation of one or more relays depending upon the voltage and current inputs used to energize the relay. It would seem that a polyphase relay would be more appropriate than a collection of single-phase relays for protecting a three-phase system. Electromechanical polyphase relays have been described in the literature,[8] and have been in use on three-phase systems for many years. Computer-based polyphase relays have also been developed.[9] Electromechanical polyphase relays utilize all three-phase voltages and currents to develop a torque, which changes direction at the balance point (zone boundary) of the relay. A suitable combination of voltages and currents must be chosen, so that this torque reversal occurs for all types of fault that may occur on a three-phase system. The reference cited above describes the operation of a polyphase electromechanical relay in greater detail. One advantage of a polyphase relay is that for most zero-voltage faults, at least some of the voltages are not zero and a proper directionality is maintained by the relay. Of course, for a three-phase, zero-voltage fault, it is still necessary to include a memory action, or a nondirectional overcurrent function as described in the previous section. Usually two polyphase relays are needed to protect against phase and ground faults. In the case of computer-based polyphase relays,[9] it is possible to use a single performance equation to cover all fault types.

### *5.7.1 Zone versus phase packaging*

We have examined the individual elements of a three-phase distance relay protection scheme without regard to the way in which each of the elements is combined in one or more relay cases. Although

the packaging has no effect on the protection of the line per se, it does have an impact on the cost of the installation and the complexity associated with testing and maintaining the relays. A complete phase protection package consists of an element for each pair of phases, i.e. phases a–b, b–c and c–a, and separate elements for zones 1, 2 and 3, plus the required timers and interfaces to the communication equipment. The timers and communication equipment are mounted separately, each in its own relay case, very often on separate panels or cabinets. The phase and zone connections can be combined in a variety of ways. All of the zones for a given pair of phases can be mounted in one relay case, referred to as 'zone packaged' or all of the phase pairs for a given zone can be mounted in one case and referred to as 'phase packaged'. The advantages and disadvantages of the two schemes relate to the common practice of testing and calibrating relays without taking the associated line out of service. This means that during testing adequate protection must be left in service. With phase packaging, all of the zones of the pair of phases being tested, i.e. the instantaneous zone 1 and the backup zones 2 and 3, are removed. The remaining phases, and their zones, remain in service. With zone packaging, each of the zones is removed, one at a time, e.g. zone 1 of all of the phase pairs is out of service, then zone 2 and then zone 3. Unless the number of zones is not equal to three, there is no difference in the number of relay cases between the two packaging schemes, but the panel arrangement may differ and, in association with the control switches and testing facilities, the wiring will differ. Ground protection is always provided by independent relays (either ground distance or directional overcurrent), and they are mounted separately so that they are in service when any of the phase relays are tested, and all of the phase relays are in service when the ground relay is tested. In addition, the testing facilities usually have provision for restoring some of the internal elements of a relay case to service while other elements are removed. The choice between the two packaging schemes is not clear cut, but usually depends upon the previous practices and personal preferences of the utility's engineering and testing personnel.

The discussion above relates to packaging electromechanical relays. It is not a problem with solid-state or digital relays. Solid-state relays have various protection functions on the same card or are connected to the same backplane within a common case. The testing facilities usually allow each element to be tested or calibrated separately without removing the other functions from service. Digital relays, of course, are tested and calibrated through the algorithm, and packaging is not an issue.

## 5.8 Relays for multi-terminal lines

Occasionally, transmission lines may be tapped to provide intermediate connections to loads, or to reinforce the underlying lower voltage network through a transformer. Such a configuration is known as a multi-terminal line, and is often built as a temporary, inexpensive measure for strengthening the power system. Although the resulting power system configuration is inexpensive, it does pose some special problems for the protection engineer. When the multi-terminal lines have sources of generation behind the tap points, or if there are grounded neutral wye-delta power transformers at more than two terminals, the protection system design requires careful study.[10] Consider the three-terminal transmission line shown in Figure 5.17. For a fault at F, there is a contribution to the fault current from each of the three terminals. Consider the relaying current and voltage at relay $R_1$. (For the sake of simplicity, we will assume this to be a single-phase system, although it must be understood that we are interested in three-phase systems, and we must consider the actual distance evaluations for each type of fault. This aspect of multi-terminal line protection is no different from the usual considerations of faults on a three-phase system.) The voltage at bus 1 is related to the current at bus 1 by the equation

$$E_1 = Z_1 I_1 + Z_f(I_1 + I_2) \tag{5.18}$$

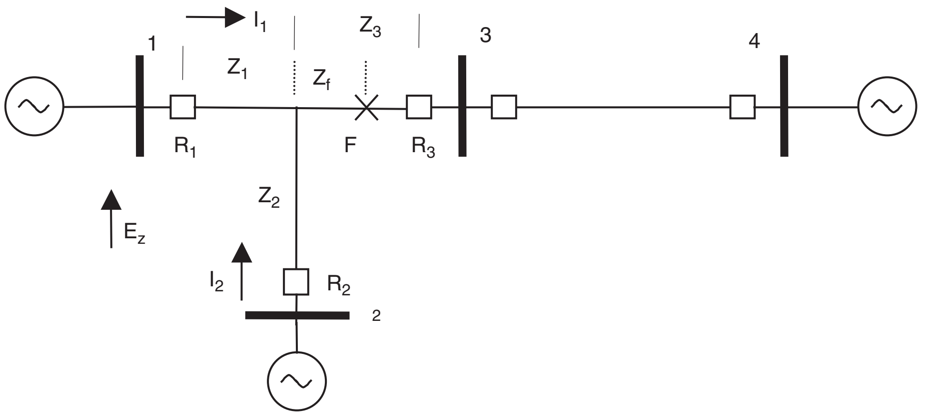


**Figure 5.17** Effect of infeed on zone settings of distance relays

and the apparent impedance seen by relay $R_1$ is

$$Z_{\text{app}} = \frac{E_1}{I_1} = Z_1 + Z_f\left(1 + \frac{I_2}{I_1}\right) \tag{5.19}$$

The current $I_2$, the contribution to the fault from the tap, is known as the infeed current when it is approximately in phase with $I_1$ and as the outfeed when its phase is opposite to that of $I_1$. Of course, completely arbitrary phase relationships are also possible, but in most cases the phase relationship is such that the current $I_2$ is an infeed current. Equation (5.19) shows that the apparent impedance seen by relay $R_1$ is different from the true impedance to the fault: $(Z_1 + Z_f)$. When the tap current is an infeed, the apparent impedance is greater than the correct value. Thus, if we set the zone 1 setting of relay $R_1$ at about 85 % of the line length 1–2, many of the faults inside the zone of protection will appear to be outside the zone, and the relay will not operate. We must accept this condition, since, when the tap is out of service, the correct performance of the relay is restored. It would be insecure to set zone 1 of the relay to a high value, in order that the apparent impedances for all faults inside the 85 % point lie inside the zone setting. For, with such a setting, if the tap source should be out of service for some reason, faults beyond the 85 % point will cause zone 1 operation.

On the other hand, zones 2 and 3 of relay $R_1$ must reach beyond buses 2 and 3, respectively, under all possible configurations of the tap. Thus, for these (overreaching) zone settings, we must set the zones with all the infeeds in service. Then, if some of the infeeds should be out of service, the impedance seen by the relay will be smaller, and will be definitely inside the corresponding zones. We may summarize simply the principle of protecting a multi-terminal line as follows: underreaching zones are set with infeeds removed from consideration, and overreaching zones are set with the infeeds restored. These ideas are illustrated in the following example.

---

**Example 5.6**

Consider the system shown in Figure 5.18. We may assume that the relative magnitudes of $I_1$, $I_2$ and $I_3$ remain unchanged for any fault on the system between the buses A through G. This is clearly an approximation, and in an actual study we must use appropriate short-circuit calculations

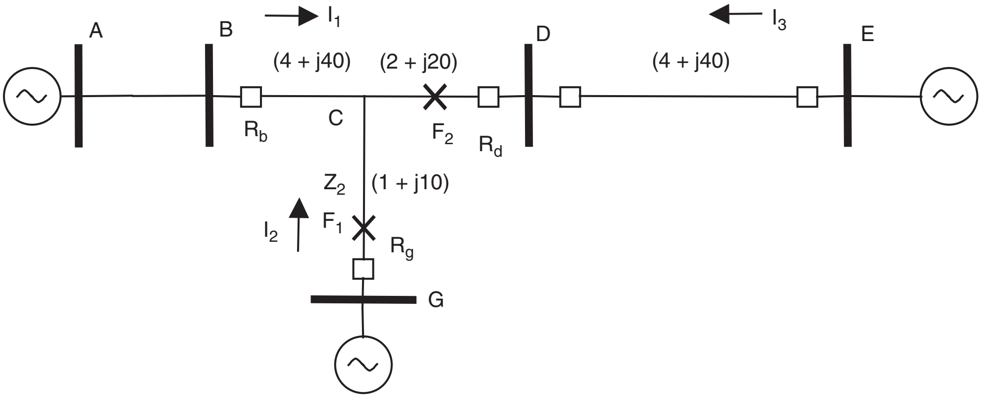


**Figure 5.18** System with infeed for Example 5.6

for each of the faults. We are required to set the three zones of the relay $R_b$. It is assumed (as determined by the short-circuit study) that $I_2/I_1 = 0.5$.

### Zone 1

This must be set equal to 85 % of the smaller of the two impedances between buses B and D, and B and G. Also, we will consider the infeed to be absent for setting zone 1. Thus, the zone 1 setting is $0.85 \times (4 + j40 + 1 + j10) = 4.25 + j42.5\ \Omega$.

### Zone 2

This is set equal to 120 % of the longer of the two impedances between buses B and D, and B and G. The infeed will be considered to be present, and will apply to the impedance of the segment C–D. Thus, the zone 2 setting is $1.2[4 + j40 + 1.5 \times (2 + j20)] = 8.4 + j84\ \Omega$.

### Zone 3

Assuming that line D–E is the only one needing backup by the relay $R_b$, the zone 3 setting is obtained by considering the infeed to be in service. The apparent impedance of the line B–D with the infeed is $(4 + j40) + 1.5 \times (2 + j20) = 7 + j70\ \Omega$. To this must be added 150 % of the impedance of line D–E, duly corrected for the infeed. Thus, the zone 3 setting of $R_b$ is $7 + j70 + 1.5 \times 1.5 \times (4 + j40) = 16 + j160\ \Omega$.

## 5.9 Protection of parallel lines

Transmission lines that are on the same tower, or paralleled along the same right of way, present unique problems to the associated line relays. The difficulty stems from the fact that the lines are mutually coupled in their zero-sequence circuits. The small amount of negative- and positive-sequence mutual coupling can usually be neglected. The zero-sequence coupling causes an error in the apparent impedance as calculated by equation (5.14).

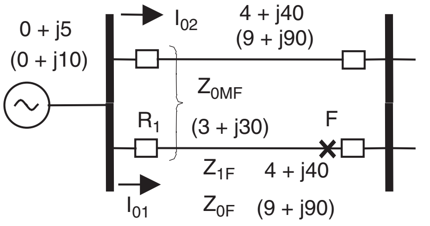


**Figure 5.19** Fault on a mutually coupled transmission line

Consider the fault at F on one of the two mutually coupled lines as shown in Figure 5.19. For a phase-a-to-ground fault, the symmetrical component voltages at relay location $R_1$ are given by (see equations (5.10)–(5.14))

$$\begin{aligned} E_{1f} &= E_1 - Z_{1f}I_1 \\ E_{2f} &= E_2 - Z_{1f}I_2 \\ E_{0f} &= E_0 - Z_{0f}I_{01} - Z_{0mf}I_{02} \end{aligned} \tag{5.20}$$

where $I_{01}$ and $I_{02}$ are the zero-sequence currents in lines 1 and 2, respectively, and $Z_{0mf}$ is the zero-sequence mutual impedance in the faulted portion of the transmission line. As before, the voltage of phase a at the fault point can be set equal to zero:

$$E_{af} = E_{0f} + E_{1f} + E_{2f} = (E_0 + E_1 + E_2) - Z_{1f}(I_1 + I_2) - Z_{0f}I_{01} - Z_{0mf}I_{02} = 0 \tag{5.21}$$

$$= E_a Z_{1f} I_a - (Z_{0f} - Z_{1f})I_{01} - Z_{0mf}I_{02} = 0 \tag{5.22}$$

$I'_a$ of equation (5.13) must now be replaced by the following:

$$\begin{aligned} I'_a &= I_a + \frac{Z_{0f} - Z_{1f}}{Z_{1f}} I_{01} + \frac{Z_{0mf}}{Z_{1f}} I_{02} \\ &= I_a + \frac{Z_0 - Z_1}{Z_1} I_{01} + \frac{Z_{0m}}{Z_1} I_{02} = I_a + mI_{01} + m'I_{02} \end{aligned} \tag{5.23}$$

And finally, in terms of this modified compensated phase current, the impedance to the fault point is given by

$$\frac{E_a}{I'_a} = Z_{1f} \tag{5.24}$$

It should be noted that the current from a parallel circuit must be made available to the relay, if it is to operate correctly for a ground fault. This can be accomplished if the mutually coupled lines are connected to the same bus in the substation. If the two lines terminate at different buses, this would not be possible, and in that case one must accept the error in the operation of the ground distance function.

**Example 5.7**

Let the system shown in Figure 5.19 represent two mutually coupled transmission lines, with impedance data as shown in the figure. The zero-sequence impedances are given in parentheses, and the mutual impedance in the zero-sequence circuits of the two transmission lines is $(3 + j30)\ \Omega$. The rest of the system data are similar to those of Example 5.4. For a phase-a-to-ground fault at F, the transmission line impedance is divided by two because of the parallel circuit of equal impedance. Thus, the positive and negative sequence impedance due to the transmission lines in the fault circuit is $(2 + j20)\ \Omega$, while the zero-sequence impedance is $0.5 \times (9 + j90 + 3 + j30) = (6 + j60)\ \Omega$. The symmetric components of the fault current are given by

$$I_1 = I_2 = I_0 = \frac{7967.4}{2 \times (0 + j5) + 0 + j10 + 2 \times (2 + j20) + 6 + j60}$$
$$= 66.169\angle - 85.23^\circ$$

The currents seen by the relay are half these values because of the even split between the two lines, and $I_a = 3 \times \frac{1}{2} \times I_1 = 99.25\angle - 85.23^\circ$. The zero-sequence currents in the two lines are

$$I_{01} = I_{02} = 33.085\angle - 85.23^\circ$$

The zero-sequence compensation factors $m$ and $m'$ are given by (see equation (5.23))

$$m = \frac{9 + j90 - 4 - j40}{4 + j40} = 1.25 \quad \text{and } m' = \frac{3 + j30}{4 + j40} = 0.75$$

The compensated phase a current, as given by equation (5.23), is

$$I'_a = I_a + mI_{01} + m'I_{02} = 165.42\angle - 85.23^\circ$$

The symmetrical components of the voltages at the relay location are given by

$$E_1 = 7967.4 - j5 \times 66.169\angle - 85.23^\circ = 7637.7 - j27.51$$
$$E_2 = -j5 \times 66.169\angle - 85.23^\circ = -329.7 - j27.51$$
$$E_0 = -j10 \times 66.169\angle - 85.23^\circ = -659.4 - j55.02$$

and the phase a voltage at the relay location is

$$E_a = E_1 + E_2 + E_0 = 6649.51\angle - 0.95^\circ$$

Finally, the impedance seen by the relay $R_a$ is

$$\frac{E_a}{I'_a} = \frac{6649.5\angle - 0.95^\circ}{165.42\angle - 85.23^\circ} = 4 + j40\ \Omega$$

Besides the effect of mutual coupling on the performance of the ground distance relay, some other relay operations may also be affected in the case of parallel transmission lines. Consider the two examples given below.

### Incorrect directional ground relay operation

Consider the system shown in Figure 5.20. A ground fault on line 2 induces a zero-sequence current $I_{01}$ in line 1. This current, in turn, circulates through the grounded neutrals at the two ends of the transmission line. The current at the A terminal of this line is out of the line, and into the bus. However, if the transformer neutral current is used for polarization of the directional ground relay, the operating and the polarizing currents will be in the same direction. This condition is identical to that corresponding to a fault on the line. Similarly, the condition at the end B of the line, with current in the transformer neutral and the line current once again in phase with each other, is indistinguishable from that due to an internal fault. The ground directional relays at both ends may be fooled into seeing this condition as an internal fault. The same false operating tendency would exist if potential polarizing were used. In other words, the phase of the polarizing quantity is not independent of the direction of current flow, as it is when a short circuit occurs.[6]

### Incorrect phase distance relay operation

This problem is encountered when phase and ground distance relaying is used for protecting parallel transmission lines which are connected to common buses at both ends.[11] Consider the case of a simultaneous fault between phase a and ground on line 1, and between phase b and ground on line 2, as shown in Figure 5.21. This is known as a cross-country fault, and is generally caused by

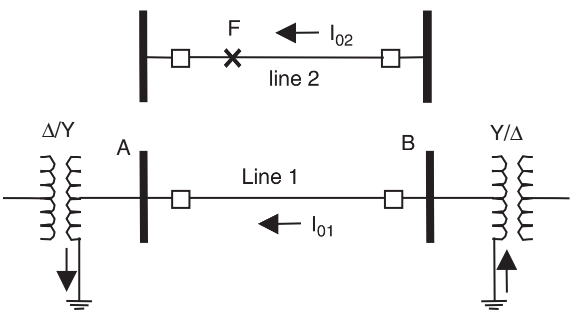


**Figure 5.20** Current polarization error caused by induced current in a coupled line

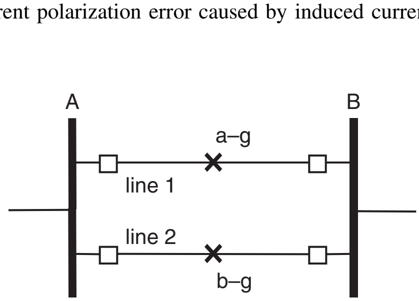


**Figure 5.21** Simultaneous faults on parallel transmission lines

the fault arc from the first ground fault expanding with time, and involving the other transmission line in the fault. Such a fault produces fault current contributions in both phases a and b of both circuits, and may be detected as a phase a–b–g fault on both lines.

A multiphase fault will cause a three-phase trip of both circuits. This problem is particularly severe when single-phase tripping and reclosing are used. In this case, the correct and desirable operation would of course be a single-phase trip on each of the circuits, maintaining a three-phase tie between the two ends of the lines, although the impedances would be unbalanced. Reference 11 examines the calculations involved, and propose a solution involving a digital relay that uses currents and voltages from all six phases. Single-phase tripping and reclosing were discussed in Chapter 1. The possibility of failure of distance relays for such faults has been well recognized in Europe, where both double-circuit towers and single-phase tripping are common.

## 5.10 Effect of transmission line compensation devices

We have assumed, so far, that the transmission system is relatively uncomplicated, and that overcurrent, distance or directional relays can be applied in a straightforward manner to provide reliable protection. There are primary transmission elements, however, that upset this arrangement. In particular, series capacitors that are installed to increase load or stability margins, or series reactors that are used to limit short-circuit currents, can significantly affect the transmission line protection. Our concern here is not the protection of the devices themselves: that will be the subject of later chapters. Our concern here is how these devices affect the transmission line protection itself.

### *5.10.1 Series capacitors*

A series capacitor can upset the basic premise upon which the principles of distance and directional relaying are founded. Thus, we normally assume that fault currents reverse their direction only for faults on two sides of a relay, and that the ratio of voltage to current at a relay location is a measure of the distance to a fault. A series capacitor introduces a discontinuity in the reactive component of the apparent impedance as the fault is moved from the relay to, and beyond, the capacitor (Figure 5.22). Depending upon the size and location of the capacitor, distance relay settings may

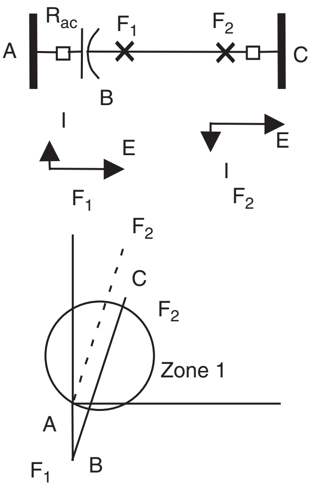


**Figure 5.22** $R-X$ diagram with a series capacitor

or may not be possible. Consider a fault at $F_1$ in Figure 5.22. The fault current now leads the voltage, and is indistinguishable from the conditions resulting from a fault in the reverse direction. As the fault moves towards $F_2$, which is at the zone 1 boundary, the apparent impedance follows the trajectory shown on the $R-X$ diagram. In this situation, the distance relay at $R_{ac}$ will fail to operate for $F_1$. It should be remembered that most series capacitors are fitted with protective devices across their terminals, such as protective gaps, surge suppressors or circuit breakers. The effect of these protective devices is to short circuit, or bypass, the capacitors in the presence of faults. Thus, the distance relays may be made slow enough so that the capacitors are first removed from service by the protective devices, and the proper operation of the distance relays is restored. An alternative scheme for protecting transmission lines with series capacitors is to use phase comparison relaying, which will be covered in Chapter 6.

### *5.10.2 Series reactors*

Series reactors introduce impedance into the line, but since the angle of the reactor is almost 90°, as is the transmission line, there is very little discontinuity in the $R-X$ diagram. This is illustrated in Figure 5.23. If the reactor can be switched in or out of service, the line impedance will change, and must be taken care of by changing the relay zone settings. The series reactors will also affect the settings of overcurrent relays, since the short-circuit currents are affected by the series reactor. However, as the series reactors are usually required for achieving safe short-circuit current levels, they are seldom taken out of service without taking the line out of service also. Consequently, the reactor can be considered to be present, and the line relays set accordingly. However, in the unlikely event that the reactor is removed from service, the line impedance will be reduced. Assuming that there are no changes in the relay setting, the relay will now see beyond its original zone of protection, i.e. it will now overreach its desired protective zone. For instance, if the reactor shown in Figure 5.23 has an impedance of $Z_{ab} = 10\ \Omega$ and the line section BC has an impedance of j40 (ignoring the resistance), zone 1 at both ends would be set at $0.85 \times (40 + 10) = 42.5\ \Omega$. If the reactor is removed from service the line impedance would be 40 Ω. With the relays set for 42.5 Ω they would see faults beyond the original zone of protection. This may be acceptable if the zone 1 overreach does not extend into the next line section.

### *5.10.3 Shunt devices*

Shunt capacitors and reactors are installed for entirely different reasons, and even if tied to the line itself usually do not have a significant impact on the transmission line relays. There is a steady-state

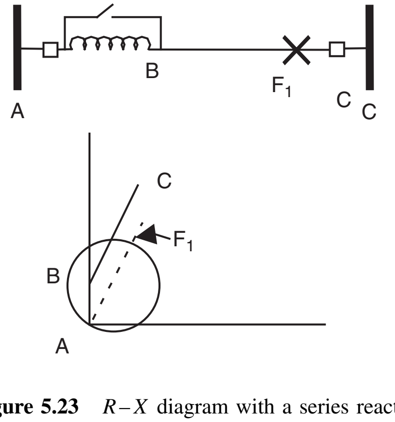


**Figure 5.23** $R-X$ diagram with a series reactor

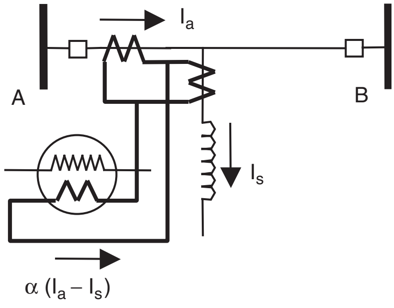


**Figure 5.24** Compensation of shunt current in a relay

load current associated with the shunt devices that is seen by the line relays, but the margins used in differentiating between load and short-circuit currents is usually sufficient to avoid any problems. If a problem does exist, it is not too difficult to connect the CTs of the shunt devices, so that the load current is removed from the line relay measurement (Figure 5.24).

## 5.11 Loadability of relays

Recall the discussion in section 5.3 of the apparent impedance seen by a relay as the load on the line changes. As the load on a transmission line increases, the apparent impedance locus approaches the origin of the $R-X$ diagram. For some value of line loading, the apparent impedance will cross into a zone of protection of a relay, and the relay will trip. The value of load MVA at which the relay is on the verge of operation is known as the loadability limit of the relay. Consider the characteristics of a directional impedance relay, and a mho relay, with a zone setting of $Z_r$ secondary ohms as shown in Figure 5.25.

If the load power factor angle is assumed to be $\varphi$ and the angle of maximum torque is assumed to be $\theta$, the value of the apparent impedance at which the loading limit will be reached is $Z_r$ for the directional impedance relay and $Z_r \cos(\theta + \varphi)$ for the mho relay (note that a lagging power factor angle is considered to be negative). If the primary voltage of the line is $E$ kilovolts (phase to neutral), and VT and CT ratios are $n_v$ and $n_i$, respectively, the loadability limit for the directional

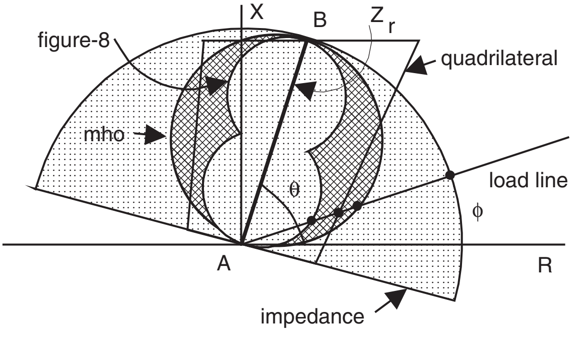


**Figure 5.25** Loadability of distance relays with different characteristic shapes

distance relay is (in MVA)

$$S_{1,\text{imp}} = 3\frac{E^2}{Z_\text{p}} = 3\frac{E^2 n_\text{i}}{Z_\text{r} n_\text{v}} \tag{5.25}$$

where $Z_\text{p}$ is the primary impedance, and for the mho relay is (in MVA)

$$S_{1,\text{moh}} = 3\frac{E^2 n_\text{i}}{Z_\text{r}\cos(\theta + E\varphi) n_\text{v}} \tag{5.26}$$

It is clear that the loadability of a mho relay is significantly greater than that of a directional impedance relay. The loadability of a relay can be further increased by using a figure-of-eight characteristic (offset mho), or a quadrilateral characteristic, as shown in Figure 5.25. The latter characteristic is achievable only with solid-state or computer-based relays.

**Example 5.8**

We will consider the loadability of the zone 1 setting of the relay from Example 5.2. (This will illustrate the principle of checking the loadability, although one must realize that the critical loadability, which provides the smaller limit, is that associated with the third zone.) The current and voltage transformer ratios for the relay were determined to be $n_\text{i} = 100$ and $n_\text{v} = 288.6$. The zone 1 setting is $1.17 + \text{j}8.84 = 8.917\angle 82.46^\circ$. From equation (5.25), the loadability of an impedance relay is given by (the phase-to-neutral voltage is 20 kV)

$$S_{1,\text{imp}} = 3 \times \frac{20^2 \times 100}{8.917 \times 288.6} = 46.63 \text{ MVA}$$

In the case of a mho relay, we must calculate the loadability at a specific power factor. Let us assume a power factor of 0.8 lagging. This corresponds to $\varphi = -36.870$. The angle of the line impedance is $82.46^\circ$. Thus, $(\theta + \varphi) = (82.46^\circ - 36.87^\circ) = 45.59^\circ$. Using equation (5.26), the loadability of a mho relay for a 0.8 pf lagging load is

$$S_{1,\text{mho}} = 3 \times \frac{20^2 \times 100}{8.917 \times 288.6 \times \cos 45.59^\circ} = 66.63 \text{ MVA}$$

Of course, one must check the loadability of all the zones, but the zone 3 loadability, being the smallest, will usually be the deciding criterion.

## 5.12 Summary

In this chapter we have examined the protection of a transmission line using distance relays. Distance relays, both single-phase and polyphase, are used when changes in system configuration, or generating pattern, provide too wide a variation in fault current to allow reliable settings using only current as the determining factor. Distance relays are relatively insensitive to these effects. We have reviewed a number of characteristics that are available depending on the protection required. We have also discussed several common problems associated with nonpilot line protection, including

the problem of excessive or unusual load, protection of multi-terminal lines, parallel transmission lines and lines with series or shunt compensation.

## Problems

**5.1** Determine the three zone settings for the relay $R_{ab}$ in the system shown in Figure 5.26. The system nominal voltage is 138 kV, and the positive sequence impedances for the various elements are given in the figure. The transformer impedance is given in ohms as viewed from the 138 kV side. Assume that the maximum load at the relay site is 120 MVA, and select a CT ratio accordingly. The available distance relay has zone 1 and zone 2 settings from 0.2 to 10 Ω, and zone 3 settings from 0.5 to 40 Ω, in increments of 0.1 Ω. The angle of maximum torque can be adjusted to 75° or 80°. Remember that the zone 3 of the relay must back up the line BC, as well as the transformer.

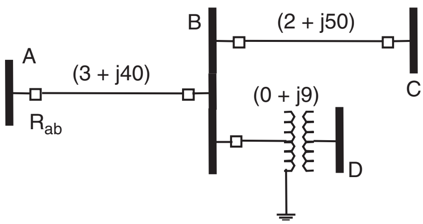


**Figure 5.26** System for problem 5.1

**5.2** Consider the system shown in Figure 5.13. Assume that F is at the end of the line. If the maximum load in the line is 10 MVA, what are the zone 1 and zone 2 settings for this line? You may assume that the available distance relay is the same as that in problem 5.1.

**5.3** For the system in Figure 5.26, and using the relay settings determined in problem 5.1, plot the three zone settings on the $R$–$X$ diagram. Also show the 120 MVA load on the $R$–$X$ diagram. You may assume a load power factor of 0.8 (lagging). Plot the load impedance when the load is flowing into the line, and when it is flowing into the bus. Is there any problem in setting a directional impedance relay with this load? If you perceive a problem, what solution do you suggest?

**5.4** Calculate the appropriate relaying voltages and currents for faults between phases a and b, and between phase b and the ground, for the system in Example 5.4. You may use the results obtained in Example 5.4 to simplify the work involved.

**5.5** Repeat the calculations for the system in Example 5.4 for a b–c–g fault. Check the response of the b–c (phase) distance relay, as well as the a–g and b–g (ground) distance relays.

**5.6** For the a–b fault studied in problem 5.4, what is the impedance seen by the b–c and c–a relays? What is the impedance seen by the a–g and b–g relays for the a–b fault?

**5.7** Consider the multi-terminal line in the system shown in Figure 5.27. Each of the buses C, D, G, H and J has a source of power behind it. For a three-phase fault on bus B, the contributions from each of the sources are as follows:

| Source | Current, $I$ |
|---|---|
| J | 600 |
| C | 200 |
| D | 300 |
| G | 800 |
| H | 400 |

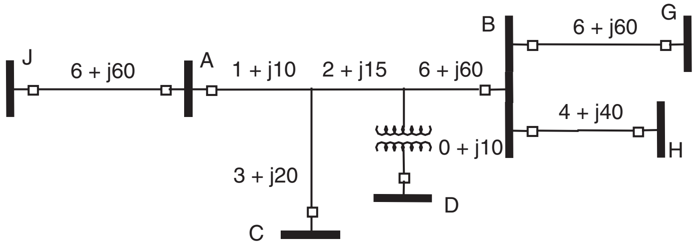


**Figure 5.27** System diagram for problem 5.7

You may assume that the fault current contributions from each of these sources remain unchanged as the fault is moved around throughout the system shown. Determine the zones 1, 2 and 3 settings for the distance relays at buses A and B. Remember to take into account the effect of the infeed for determining the zones 2 and 3 settings, while no infeeds are to be considered for the zone 1 settings.

**5.8** For relays $R_d$ and $R_g$ at buses D and G in Figure 5.18, determine the settings for the three zones of their distance relays. You may assume that the positive sequence impedance of line AB is $(3 + j30)\ \Omega$. Also, you may assume that nothing beyond bus G needs backup. Assume $I_2/I_3 = 0.5$.

**5.9** In the problem considered in Example 5.7, the current in the parallel circuit is not available to the relay $R_1$. What is the impedance seen by the ground distance relay if $I_{02}$ is omitted from the relay? Is it necessary to set the ground distance relay differently to accommodate this error?

**5.10** A zone of a distance relay is set at 10 Ω secondary. The CT ratio is 500 : 5 and the VT ratio is 20 000 : 69.3. What is the fault resistance which this relay tolerates for a fault at a distance of 80 % of the zone boundary? Find the answers for a directional impedance relay, and also for a mho relay. You may assume that the remote terminal of the line is out of service. The line impedance angle and the relay maximum torque angle are both equal to 80°.

**5.11** For the system shown in Figure 5.19, a simultaneous fault occurs on phase b to ground on line 1, and phase c to ground on line 2. The fault is at the midpoint of the lines. You may assume that there is no source connected to the far end of the lines. (a) Calculate the phase-to-neutral voltages at the sending end of the lines, and the phase currents in the two lines. (b) What is the impedance seen by the phase (b–c) distance relays of the two lines?

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